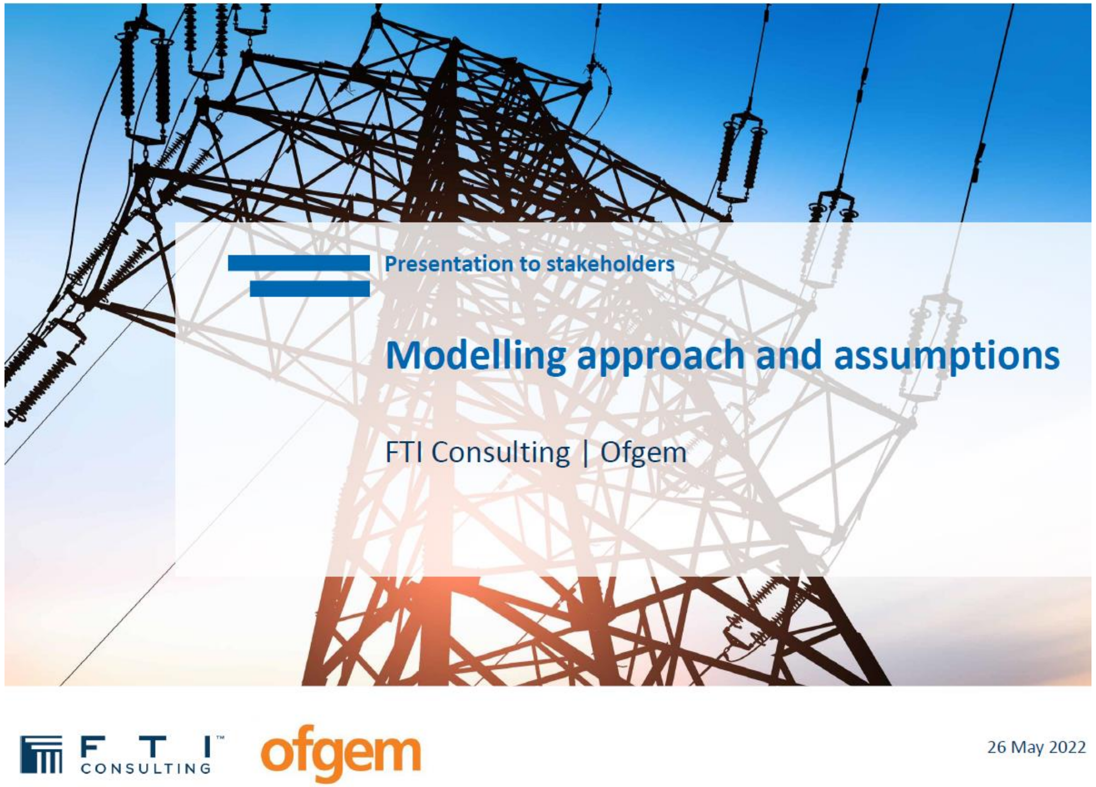
Prepared for SSE

Response to Ofgem Call for Input on Locational Pricing Assessment

June 2022

Ofgem Locational Pricing Assessment

Introduction



Ofgem is undertaking an assessment of the potential benefits, costs and implementation requirements associated with transitioning to a zonal or nodal wholesale market design.

Working with FTI consulting, they have developed a work programme to assess if introducing locational granularity into the wholesale electricity market will better enable a fully flexible, low carbon, low cost system with the aim of finalising the assessment by October 2022.

The proposed modelling approach and assumption were presented to stakeholders on 26th May 2022. Following this a call for input was published asking 3 questions:

1. The key opportunities associated with introducing more granular locational pricing in GB;
2. The key implementation challenges, risks and mitigations; and
3. The proposed approach to modelling zonal and nodal market designs

SSE have commissioned LCP and Frontier to prepare a response to these 3 questions, primarily focusing on question 3 and highlighting some of the key implementation challenges.

Using the presentation given to stakeholders and accompanying note, the proposed approach and assumptions have been assessed and recommendations for improvement given.

Key implementation challenges

Key implementation challenges

Careful consideration is needed to assess implications of LMP for liquidity

In the past, Ofgem has considered market liquidity a key issue, and therefore it will be important to ensure that implementing LMP does not materially affect liquidity going forward

Liquidity

- Markets with LMP can be liquid, such as PJM in North-Eastern US. But this is not universally true – levels of forward liquidity vary significantly across different US LMP markets. Therefore the PJM experience may not directly, or quickly, translate into the GB context.
- There are a number of key implementation questions:
    - To support liquidity under LMP, trading will typically occur at ‘hubs’ – raising a question as to how these will develop i.e. will they develop naturally and if so over what timeframes, or created by regulation?
    - Where prices are not close to or correlated with hub prices, forward liquidity will need to be supported through the allocation of Financial Transmission Rights (FTRs). However, FTR markets are very complex to develop, and there is a key question as to whether they can deliver the necessary liquidity in products that match generator locational risk profiles (e.g. term, shape), particularly over investment timescales.
- In addition, any assessment of liquidity should consider the impacts relative to a counterfactual i.e. there may be good reasons to believe that, all else equal, liquidity is reduced in LMP markets.

Given the outcome with respect to liquidity it will be important to test the impact of low and high liquidity scenarios within the modelling framework, clearly describing how the modelling takes this into account

Key implementation challenges

There may be transitional and enduring cost of capital impacts to consider with important implications for achieving Net Zero

Transitional effects

- Significant and extended market reform creates transitional uncertainty. Even if LMP were judged to be successful in its own right, it is only one part of the market design to achieve Net Zero and energy security.
- Support mechanisms (e.g. CfDs) will need to be adjusted to reflect LMP, and therefore during the transitional period investment will either be:
  - delayed, which is not compatible with achieving Net Zero and energy security; or
  - more expensive, as an inefficient risk premium is added due to the uncertainty over the reference price.

Enduring effects "Steady-state"

- Over the life of an investment, investors under LMP may be exposed to increased revenue volatility increasing the cost of capital, and therefore, it will be important to consider in both the counterfactual and LMP factual, factors which could affect the cost of capital such as:
  - "*transmission cost*" volatility (i.e. volatility of TNUoS versus volatility in locational prices spreads under LMP); and
  - *"volume risk"* i.e. under LMP wind farms would not be compensated for system curtailment (in contrast to the present day), and therefore will face significant new risks related to the volume of curtailment over life of investment. In turn, risk is related to the build-out of T network which generators are not well-placed to manage.
- If LMP design exposes investors to additional new risks which they are not well-placed to manage, this contradicts principles on which CfDs were based i.e. to remove such risks and reduce cost of capital to the benefit of customers. If however, investors are protected from this risk in line with EMR, then this undermines potential rationale of LMP

There is also an important design question whether CfDs should be exposed to nodal price volatility to preserve locational signal they face, which will have implications for the cost of capital assumed

It will be important to consider the impacts on the cost of investment relative to the counterfactual - given volume of investment expected, even small increments on the cost of capital could significantly increase costs of the transition to Net Zero.

Key implementation challenges

Important to consider the impact political acceptability of locally varying prices may have on LMP design and any benefits

Political acceptability

- LMP implies that both generation and demand face nodal prices, meaning end-consumers may face different prices depending on their precise location
- The political sensitivity of locally varying prices may mean that either:
  - following a period of transitional uncertainty LMP is ultimately not implemented; or
  - If LMP is implemented it will be with consumers facing national or zonal average prices, rather than nodal.
- In other markets, this averaging has been at the transmission level, suggesting locally varying prices at the distribution level would be even less palatable (even if they were practically deliverable).
- As a result, nodal signals will be diluted and not sufficiently granular to steer all locational decisions that will be important for Net Zero.
  - Given the need to support lots of smaller investments to achieve net zero (e.g. local storage, rooftop solar, EV chargepoints) getting these in the right place is really important.
  - But without locationally varying signals down to this level of granularity for both generation and demand, LMP will be less effective, and other solutions will still be needed.
- It will be important to assess the benefits of LMP design without demand-side nodal signals, and consider the benefits that could be achieved with less significant interventions such a exposing more customers to the wholesale price and through an improved demand TNUoS signal, which is currently being considered by the TNUoS Task Force.

Assessment of modelling approach

Project Overview and Scope

The proposed assessment is limited in scope and risks not fully addressing project objectives

ofgem | FTI CONSULTING

Project overview: This project is part of our Full Chain Flexibility Strategic Change Programme

Central question	Will introducing locational granularity into the wholesale electricity market enable a fully flexible, low carbon, low-cost system?
Purpose	Produce a technical assessment of alternative wholesale market designs that considers: • the role for locational granularity in enabling power sector transformation and • the extent to which (and how) the locational granularity of electricity in the wholesale market could increase to best achieve this.
Objectives	• Identify a range of feasible market designs that vary according to how granular the locational value of electricity is (e.g. national, zonal and nodal) • Assess the potential benefits, costs and distributional impacts associated with specific models and design choices • Identify possible design choices and implementation pathways

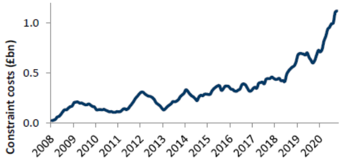
9

FTI CONSULTING

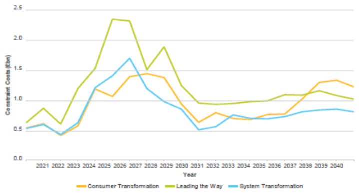
The ESO have identified several issues with the current working of energy markets which could affect GB's aim to achieve a cost-effective, secure pathway to Net Zero

1 In particular, according to the ESO, constraint costs are *"rising at a dramatic and accelerating rate"*

Congestion costs have increased 8-fold since 2010 at a cost of £7bn to customers…



… these costs are anticipated to be sustained at high levels – at a cost of c.£13bn to £19bn to 2035



2 ESO identified three other issues with market design:

Balancing role	Balancing role increasingly challenging – system operator **no longer "residual"** in market
Interconnector and storage flows	Interconnectors and storage are important sources of flexibility but at times currently **exacerbate constraints**
Flexibility resources	Current market design **does not unlock full potential** of diverse ranges of flexibility resources

3 Additionally, other potential issues are:

Siting Decisions	Locational signals provided by TNUoS may not be **sufficient to incentivise an efficient siting of generation and demand**

12

The central question of the assessment is too limited in scope to provide a full assessment of whether nodal or zonal pricing should be introduced.

Nodal or zonal pricing are not the only way that the issues National Grid ESO have identified could be solved. For example, more efficient locational signals through the current TNUoS regime could reduce constraint costs and provide better incentives for flexibility to locate where it is needed, and improved network investment in line with generation investment could also reduce constraint costs.

To be able to fully assess the benefits of introducing locational granularity, **alternative changes to market arrangements in addition to nodal and zonal pricing should be tested** in order to provide a comparison of all options. Given work is already ongoing to identify improvements to the TNUoS regime, as a minimum the national pricing counterfactual should assume more efficient TNUoS signals can be assumed.

The central question should also ask if changing market arrangements _better_ enables a fully flexible, low carbon, low cost system. The current wording suggests that the assessment will only cover whether it is possible to achieve this through introducing locational granularity, even if that means higher total system cost while delivering customer benefit via redistribution. This sets the bar too low for the assessment.

Approach to Assessment (1)

The assessment should be conducted on a system cost basis

The transition to more granular locational pricing have the following key impacts – these will assessed either quantitatively or qualitatively

Type	Effect	Quantitative
Short-run impact *(Operational)*	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	✓
	Reduced cost of congestion to be borne by consumers	✓
	More efficient dispatch across all resource types including **flexibility resources**	✓
	Surplus revenues from congestion rent and losses	✓
	Operational impacts from central dispatch system relative to	
Long-run impact *(Investment)*	Greater price signals to incentivise **generation and s** more efficient locations	✓
		✓
Costs / Other		
	Other policy interactions	
	ESO system implementation costs	
	Market participant costs	
	Changing **risk profiles** of market participants including **financing cost**	

From the information provided, it is **unclear if the assessment will be made on a system or consumer cost basis** (as was done in FTI's work for Octopus/ESC). Some quantitative elements would only affect consumers and others are a system level impact.

The **assessment should be conducted on a system cost basis,** supported by analysis of distributional impacts, in line with government appraisal guidance outlined in the Green Book.

For example, the assessment should not be including both wholesale price changes (consumer cost impact) and more efficient dispatch (system cost impact).

More efficient dispatch will depend on the assumed efficiency in the counterfactual**. Low cost changes could be made to improve ESO redispatch efficiency with minimal impact on wider market**. This should be tested as part of the assessment

While the key short run impacts have been identified, **surpluses from congestions rents and losses are not a system cost**, and would be a transfer between producers and network owners (and ultimately consumers) meaning they should not be included within overall system costs but within distributional impacts.

In addition, **congestion rents for TOs would be offset by lost locational TNUoS revenue which should be included in the assessment**. And ultimately the consumer should be unaffected (if network build is unchanged) due to the presence of the residual, which collects allowed revenues not recovered by congestion rents in LMP or locational TNUoS.

Approach to Assessment (2)

How the long-run impacts are modelled and quantified should be transparent

The transition to more granular locational pricing have the following key impacts – these will assessed either quantitatively or qualitatively

Type	Effect	
Short-run impact *(Operational)*	**Changes in wholesale prices** (lower in export import-constrained areas)	
	Reduced cost of congestion to be borne by c	
	More efficient dispatch across all resource ty	
	Surplus revenues from congestion rent and l	
	Operational impacts from central dispatch system relative to the BM	
Long-run impact *(Investment)*	Greater price signals to incentivise **generation and storage to site** at more efficient locations	✓
	Greater price signals to incentivise **demand to site** at more efficient locations	✓
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	
Costs / Other	Changes to **CFD payments**	✓

Further explanation is needed on how nodal pricing provides a 'greater signal' strength for more efficient locations for generation, storage and demand compared to locational TNUoS (both in its current form and with reforms).

The size of the signal is not in itself important; the key is improved accuracy (relative to an improved TNUoS) and more investable signals that parties can respond to. This should be tested against a range of possible futures.

It is unclear how the 'greater price signals' long run impact will be quantified within a system cost assessment.

Capex and opex of these technologies would not necessarily change as a result of changing location so impacts would only flow through in terms of short run impacts defined above.

How generation, storage and demand relocate to more efficient locations as a result of greater price signals will be heavily driven by the model assumptions and modelling methodology, therefore transparency on these is key.

The scenarios and the assumptions need to be transparent and provided in more detail than they currently are for stakeholders to see how the economics of the technologies might change subject to various locational constraints and changes to locational granularity.

Approach to Assessment (3)

More detail is needed on potential cost impacts and impacts on network investment

LCP INSIGHT CLARITY ADVICE

frontier economics

FTI CONSULTING

The transition to more granular locational pricing have the following key impacts – these will assessed either quantitatively or qualitatively

Type	Effect	Qua
Short-run impact *(Operational)*	**Changes in wholesale prices** (lower in export-constrained areas and higher in import-constrained areas)	
	Reduced cost of congestion to be borne by consumers	
	More efficient dispatch across all resource types including **flexibility resources**	
	Surplus revenues from congestion rent and losses	
	Operational impacts from central dispatch system relative to the BM	
Long-run impact *(Investment)*	Greater price signals to incentivise **generation and storage to site** at more efficient locations	
	Greater price signals to incentivise **demand to site** at more efficient locations	
	Improved signals for **transmission development** (due to transparent wholesale prices between different nodes)	
Costs / Other	Changes to **CFD payments**	✓
	Other **policy interactions**	
	ESO system implementation costs	✓
	Market participant costs	✓
	Changing **risk profiles** of market participants including **financing cost**	✓

A clearer and more detailed explanation is required on why moving to nodal pricing would improve network development and investment. The CBA process used in NOA would still be the driver of network investment decisions with forecasts of nodal prices replacing forecasts of constraint costs. This process still needs to anticipate future value over the life of a network asset and network congestion needs to be anticipated well in advance. Responses to price signals from generation, demand and network investment is slow and lumpy, so will not be perfect, or instantaneous. Therefore **it is not viable to wait until a nodal pricing congestion arbitrage emerges, then build the network in response.**

The impact of nodal pricing could potentially be to reduce long-run network investment due to changing locations of generation so at the margin NOA decisions may be different, but the decisions themselves should be of similar quality. So **it is unclear why nodal pricing would improve network development/investment signals.**

It is highlighted that system implementation costs, market participant costs and changes to financing costs will be quantified but it is unclear from subsequent slides how these will be factored into the modelling and what the assumptions will be.

These costs are vital to be able to fully assess impacts of locational granularity and have been absent from other studies so stakeholders will require further detail on these.

Zonal and Nodal Market Design

Chosen options for zonal and nodal wholesale market designs are appropriate but wider range should be tested

Locational granularity | Modelling scenarios

FTI CONSULTING

To model zonal market design options, we propose to use seven zones following the most constrained boundaries as defined by the ESO

Options	Number Zones / Nodes	Pros	Cons
1 *Pre-BETTA split*	2	• Splits along a boundary with the most significant constraint costs • Might address stakeholder concerns regarding liquidity	• Unlikely to be meaningful given planned Tx reinforcements and evolving electricity system
2 *Main constraint zones (currently observed)*	7	• Based on the set of most significant constraint boundaries • Defined by the ESO – objective • Might address stakeholder concerns regarding liquidity	• Historically-observed and hence may not be reflective of the future as the Tx network continues to evolve
3 *NOA & ETYS zones (currently identified)*	20[1]	• Boundaries developed based on SQSS requirements • Identifies additional, less critical, network bottlenecks	• Some boundary zones overlap or represent the subset of larger constraint boundary • Highly fragmented
4 *BID3 model zones*	60[2]	• Consistent with the approach used in FES market modelling (may vary over time depending on generation fleet)	• Zones are not fixed and vary for different technologies • Zones do not reflect constraint boundaries

Q: What are your views on the zonal market design options we should model?

Notes: (1) NOA defines 18 active constraint zones in the latest NOA7; the ETYS defines 23 zones
(2) Based on NG's Long-term Market and Network Constraint Modelling

20

Locational granularity | Modelling scenarios

FTI CONSULTING

To model nodal wholesale market design, we propose to use transmission substations to better reflect the network topology

Options	Number Zones / Nodes	Pros	Cons
1 *GSPs only (i.e. interface between Tx and Dx network)*	500+	• Based on the number of GSPs which are well defined and well understood within the industry • Likely to be sufficient to capture majority of the transmission constraints	• Does not fully align with transmission network topology • Calculation of the losses will deviate from actual observed values
2 *Transmission substations[1]*	750+	• Better reflects generation location (e.g. includes generation-only nodes) • More accurate representation/calculation of the overall network losses	• More computationally challenging than option above
3 *All nodes identified in PowerFactory model*	1800+	• Representation of the ESO network model as used for system planning (and not necessarily for market modelling)	• A large number of nodes are defined historically and may not be relevant as it does not represent the actual system configuration
4 *Include all the Distribution level nodes*	10,000+	• More accurate representation of the combined transmission and distribution network	• ESO has no visibility over distribution level nodes • Not aligned with SoW of being "transmission-first" • No evidence of a 'needs case' to introduce dynamic locational price signals at the distribution level • No international precedent for distribution LMPs

Q: What are your views on the nodal market design options we should model?

Notes: (1) Transmission substation includes any point on transmission network where two or more circuits connect (TX/DX, TX/Generator, Tx/Tx interface).

21

Of the options outlined for nodal and zonal pricing, **using "Main constraint zones" and "Transmission substations" are appropriate to model** given they best reflect current constraints and generation locations**. However a wider range of granularity should be tested**.

The step change from 7 to 750 locations is very large so **there is a risk that invalid conclusions on granularity could be made from only 2 tests**. For example, if 750 shows benefits over 7, concluding that "more granular is better", when in fact something in the middle, like a more granular version of zonal, would show the highest benefits. In addition, in the **7-zone model should be updated through time if constraints on the system move materially** which would address the key drawback of this option.

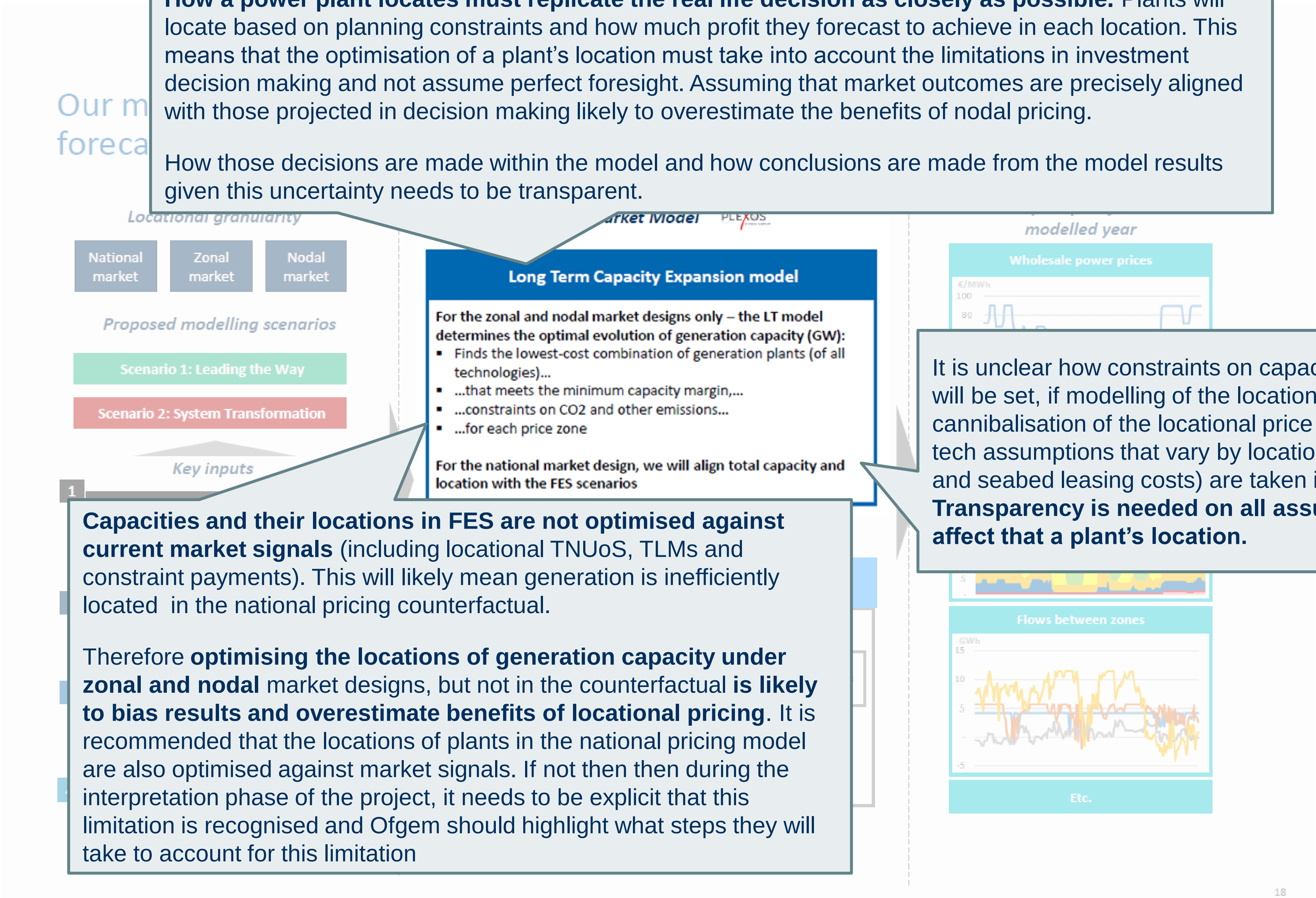
The pros and cons listed here are a limited subset and the full assessment should look at these in more detail. For example, the specific nodal locations of new generation capacity and the reinforcements of the network at nodal granularity relies on FES assumptions (in the counterfactual) that are likely to be largely spurious when looking many years into the future.

Power plant location approach

Plant locations must replicate the real life investment decisions and should be optimised for current market conditions in the counterfactual

How a power plant locates must replicate the real life decision as closely as possible. Plants will locate based on planning constraints and how much profit they forecast to achieve in each location. This means that the optimisation of a plant's location must take into account the limitations in investment decision making and not assume perfect foresight. Assuming that market outcomes are precisely aligned with those projected in decision making likely to overestimate the benefits of nodal pricing.

How those decisions are made within the model and how conclusions are made from the model results given this uncertainty needs to be transparent.



Capacities and their locations in FES are not optimised against current market signals (including locational TNUoS, TLMs and constraint payments). This will likely mean generation is inefficiently located in the national pricing counterfactual.

Therefore **optimising the locations of generation capacity under zonal and nodal** market designs, but not in the counterfactual **is likely to bias results and overestimate benefits of locational pricing**. It is recommended that the locations of plants in the national pricing model are also optimised against market signals. If not then then during the interpretation phase of the project, it needs to be explicit that this limitation is recognised and Ofgem should highlight what steps they will take to account for this limitation

It is unclear how constraints on capacities in each zone will be set, if modelling of the locational signal captures cannibalisation of the locational price signal and if other tech assumptions that vary by location (e.g.: load factor and seabed leasing costs) are taken into account. **Transparency is needed on all assumptions that affect that a plant's location.**

Scenarios

Proposed scenarios do not reflect latest government ambitions and are limited in range of outcomes

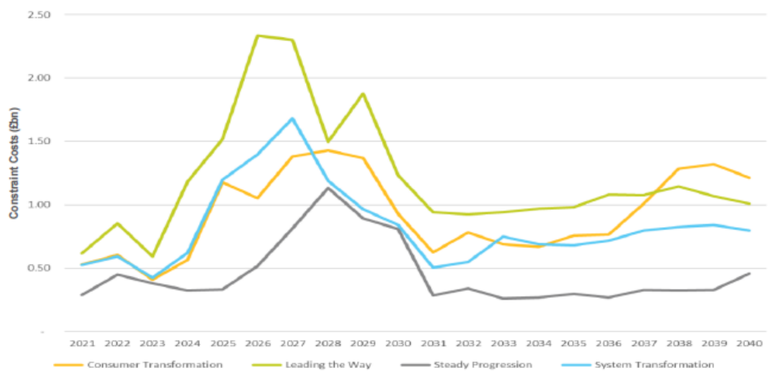
Locational granularity | **Modelling scenarios**

FTI CONSULTING

We intend model two FES scenarios which would map out a wide range of possible outcomes from the model

- Propose to select **two FES 2021 scenarios** that provide the widest range of total system constraint costs, in order to capture the range of system constraint outcomes.
- In addition, these scenarios should be **Net Zero compliant** and, ideally, at least one CB6 compliant.
- Based on ESO's NOA6 publication, we recommend using the **Leading the Way** and **System Transformation** scenarios.

NOA 6, constraint costs by FES scenario, 2021 to 2041



Scenario 1: **"Leading the Way"**
- ✓ Corresponds to the most constrained GB system (i.e. **'upper bound' scenario**)
- ✓ CB6 compliant
- ✓ Based on ESO's initial data provided

Scenario 2: **"Consumer Transformation"** vs **"System Transformation"**
- **CT** is CB6 compliant…
- …while **ST** misses the CB6 target by a small margin
- **ST** has lower constraint costs than **CT** and would be a **better 'lower bound' scenario** on the basis of NOA6…
- …and **ST** is expected to lead to materially lower constraint costs than **CT** under NOA7.
- Propose to **model System Transformation** to capture a wider range of constraint outcomes.

- Note: **Steady Progression** is currently seen as less preferred as it does not meet Net Zero by 2050

Note: We will be running the model ahead of FES 2022 publication

Q: What are your views on the scenarios we should model?

While it makes sense to test net zero scenarios with a wide range of system constraint costs, the FES scenarios only cover a limited range of outcomes.

A wider range of scenarios need to be tested to fully assess the impacts of locational granularity with scenarios developed based on identification of key drivers that could influence costs, benefits and system objectives.

This should include but not be limited to varying assumptions on gas prices, carbon prices, capacity mix, technology costs, network build out, network costs and demand. **These should be tested as full scenarios rather than sensitivities only**.

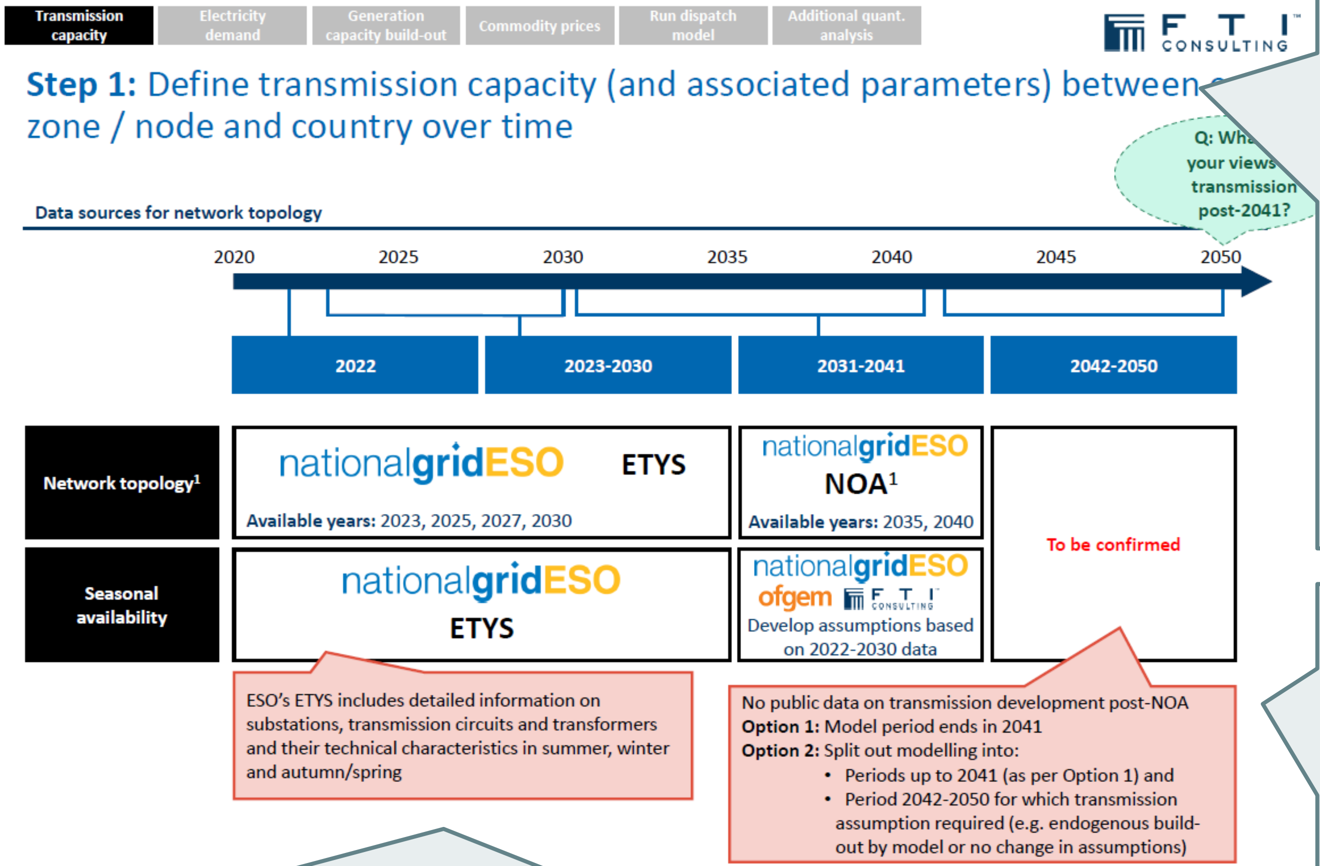
FES 2021 scenarios are now out of date and do not align with latest government strategy on capacity or network investment. Although FES 2022 will not be published in advance of the modelling, modifications to FES scenarios should be made to align with the Energy Security Strategy and to ensure that the System Transformation scenario is CB6 compliant.

FES 2021 scenarios are very different from published BEIS and CCC scenarios, particularly on demand levels. **At least 1 scenario should better align to BEIS scenarios,** if the aim of the study is for Ofgem to influence BEIS thinking**.**

Assessment of key assumptions

Transmission Network Capacity

Transmission network capacity should vary between national and locational pricing models and network build out scenarios should be tested



There is significant uncertainty around future transmission network capacity. Improvements in planning processes, as outlined in the British Energy Security Strategy, could lead to faster transmission network deployment than is assumed under NOA resulting in lower constraint costs.

Modelling against a high constraint cost background may overestimate the benefits of locational granularity in the wholesale market so a faster transmission network build out should be tested. Using the ETYS and the NOA are the right starting points for transmission network capacity but **alternative scenarios that vary transmission network build out should be run** to highlight the impact of this key uncertainty on the benefits of locational wholesale pricing.

An often cited **benefit of nodal pricing is savings from reduced transmission network build out** due to more efficient locating of plants. However, it does not appear that this is being tested in the assessment. To capture this potential benefit**, transmission network capacity should be varied between the counterfactual and the zonal/nodal pricing scenarios.**

The impact that varying the transmission network capacity between scenarios has on reaching carbon targets should be considered as well as the costs of the network investment and how these costs balance against costs of generation relocating.

Transmission network capacity is one of the most important assumptions in the assessment.

As a result, **more transparency on transmission network capacity assumptions is needed** so stakeholders can understand the implications this assumption has on results. For example, it would be useful to know what the assumptions on network capacity is between sample years and the approach taken post 2040.

Electricity Demand

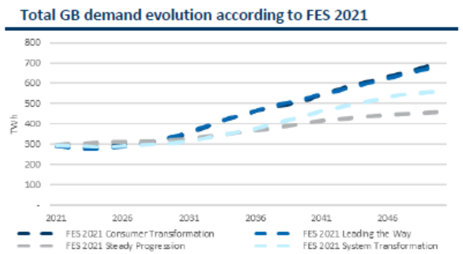
Some assumptions around demand are unclear and should be made more transparent

Transmission capacity | **Electricity demand** | Generation capacity build-out | Commodity prices | Run dispatch model | Additional quant. analysis

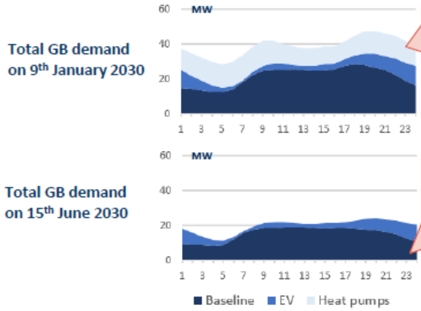
FTI CONSULTING

Step 2: Define the evolution of demand levels for each node, together with an hourly demand pattern, and flexibility assumptions by demand type

A Define **annual demand** by node, by year and by demand type



B Define **hourly demand profiles** by demand type (where possible)



Note: EVs, heat pumps are further optimised in each zone according to prices

Note: We use the same pattern for baseline demand in all zones to reflect ESO's approach

C Define **flexibility assumptions** (i.e. price responsiveness) by demand type

Sum of demand type = total demand

Demand type	Flexibility assumption
Baseline demand	Demand side response at given £/MWh
Industry electrification	Optimised to reach 75% yearly load factor
Electric vehicles	Certain % of demand is flexible; Fixed units follow exogeneous pattern; Flexible unit are optimised endogenously
Heat pumps	Certain % of demand is flexible; Fixed units follow exogeneous pattern; Flexible unit are optimised endogenously
P2G	All demand is optimised endogenously by the model
Storage	All demand is optimised endogenously by the model

Note: more detail provided in the Appendix

D Assess impact of **demand portability** (i.e. energy-intensive consumers decide to relocate/site to different locations)

Demand relocation between the zones/nodes is not modelled endogenously

Option to model benefits from demand portability with exogenously-defined sensitivities

The **assumptions for demand locations and how these could change with nodal pricing are not clearly defined**. How demand is allocated and demand patterns vary across zones/nodes could be a key driver of results, so more transparency is needed around these assumptions.

In the assessment, a breakdown of the benefits should be provided so stakeholders can see the benefit coming from demand portability separately.

Relocating industrial demand could increase nodal pricing benefits but **may not be practical or desirable from other viewpoints** so separating out this benefit would enable a better understanding of the assessment.

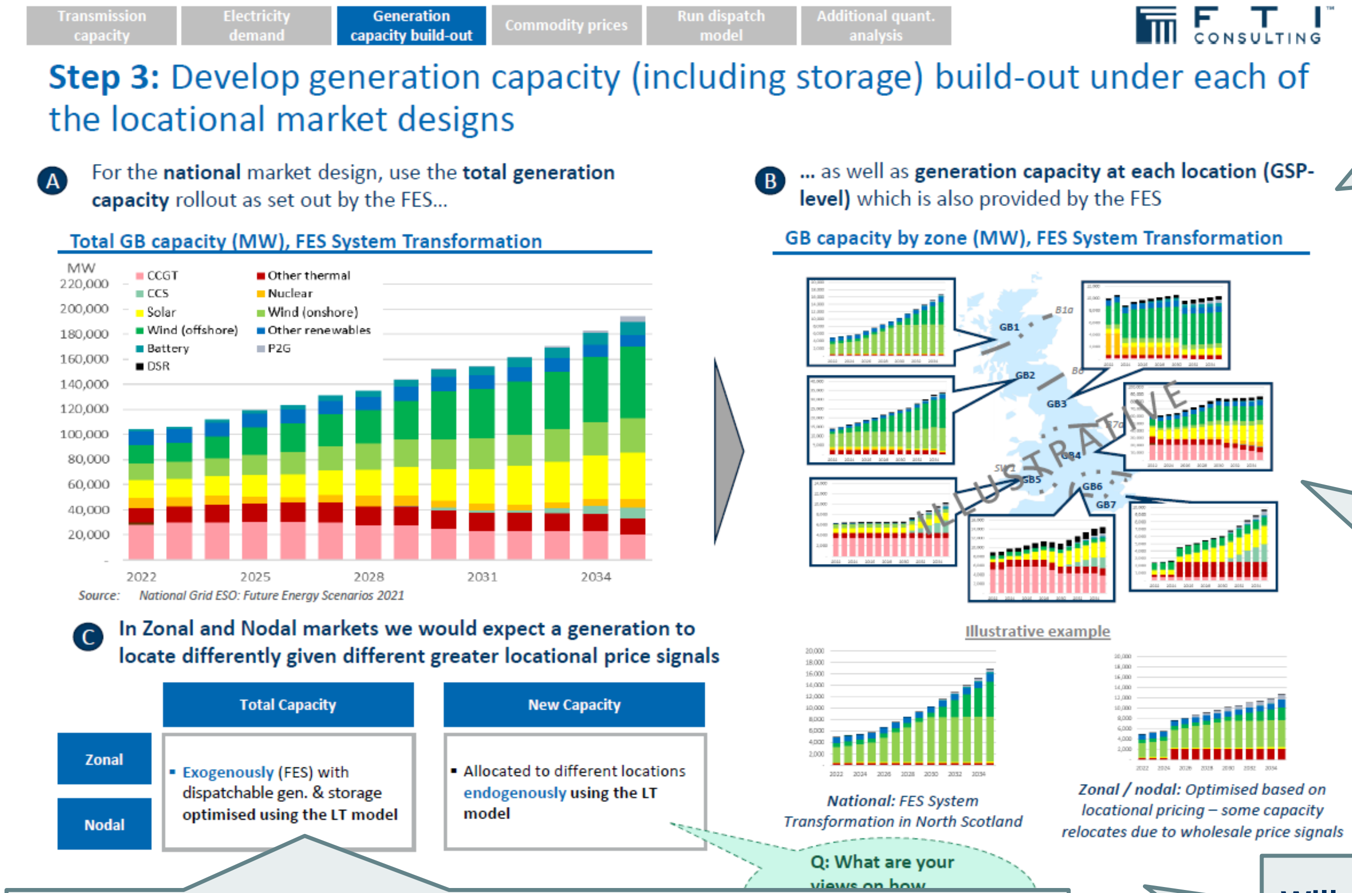
Industrial electrolyser load factor of 75% is very high given the low carbon hydrogen standard that is likely to apply to industrial electrolysers. The power sector's carbon intensity is unlikely to be low enough in 75% of hours across the year to allow them to operate. In comparison, FES assumes around 35% load factor for electrolysis.

As electrolysers are one of the main sources of portable demand, **this could overstate the benefit of locating these units in generation constrained regions**.

Details on the assumptions used on EV and HPs and the impact that their optimisation has on the modelling outcomes need to be transparent, given the significant uncertainty around EV and HP levels and profiles.

Generation Capacity Build-out (1)

All factors that influence location should be included within the modelling



New capacity is endogenously located based on response to the locational signal. Within this process, **to what extent is perfect foresight of nodal prices assumed?**

Does the modelling of the locational signal capture the potential cannibalisation of this signal?

These assumptions are likely to have an impact on results so transparency is needed here

Location may be influenced by other factors separate from locational signals such as load factors and capex costs. For example, wind load factors in Scotland are higher than in England and seabed leasing costs for offshore wind are higher in England than in Scotland. These should be factored into the plant's location decision within the modelling.

Does this mean that only dispatchable generation and storage total capacity are being changed under nodal and zonal pricing? In reality, **these changes to the system could affect build levels of other technologies too.** For example, planning restrictions in England mean onshore wind could not relocate from Scotland so other technologies such as Solar may build in England instead under a nodal pricing model. This could be a useful sensitivity to test.

Will diversity effects of relocation be taken into account? Increased diversity of wind locations across the country could increase the contribution wind as a whole makes to security of supply. But this will need to be balanced against lower load factors for wind in some locations.

Generation Capacity Build-out (2)

More detail on the max capacity within zones/nodes for each technology is required as this could be a significant driver of overall results

Transmission capacity | Electricity demand | **Generation capacity build-out** | Commodity prices | Run dispatch model | Additional quant. analysis

FTI CONSULTING

Capacity input data is based on the FES 2021, while inputs for our long-term model are based on European benchmarks

Data sources for generation capacity

	Nuclear	Thermal	Renewable	P2G	Storage
Capacity build-out input	nationalgridESO Future Energy Scenarios 2021				
CAPEX	European Commission EC Technology Pathways: 2020 Reference scenario				Bloomberg NEW ENERGY FINANCE
Efficiency of new units	entsoe TYNDP 2022			entsoe/FTI CONSULTING Battery: 90% P2G: 45%	
Max capacity per technology in zones/nodes	To be confirmed – some sites are fixed (e.g. nuclear), and some sites are limited (e.g. offsh				

For the demand levels assumed, using the capacities from FES for most technologies is appropriate. However, **alternative capacity mixes should be tested** to understand their impact; in particular higher total capacity mixes in line with the higher demand assumed by BEIS.

FES also has limited levels of long duration storage. Increasing this in the counterfactual or in alternative scenarios could make a significant difference to results so would be a useful scenario to test.

Taking dispatchable generation capacity direct from FES could exacerbate constraint costs. LCP analysis, using the model National Grid themselves use for Capacity Market auctions, shows that FES may underestimate the firm capacity required to ensure security of supply.

Sufficient firm capacity should be included within the modelling in order to avoid security of supply issues and give a more realistic view of future capacity requirement.

The max capacity per technology in zones/nodes is a key assumption that could drive overall results. There needs to constraints on how much capacity can build in each zone/node as this will affect where plants can move to help reduce constraint costs. Given the importance of this assumption, **there needs to be transparency on how this is defined.**

BEIS provide assumptions on GB plants for new unit costs across a wide range of technologies in the generation costs report. Should these be used rather than European data?

Dispatch modelling

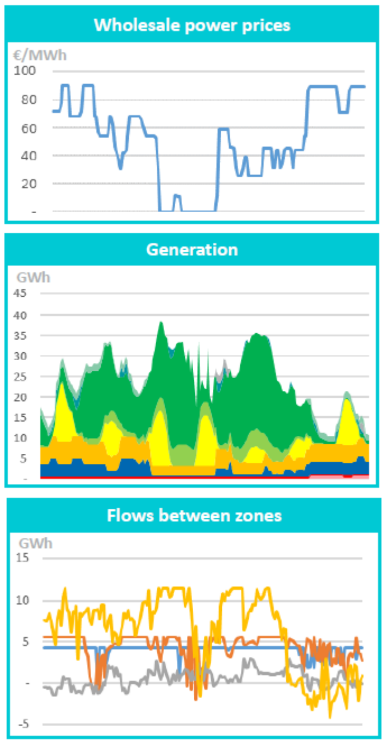
Variance to approach to remove perfect foresight should be included as a deterministic-only view could overstate benefits

Transmission capacity | Electricity demand | Generation capacity build-out | **Run dispatch model** | Additional quant. analysis

FTI CONSULTING

Step 4: Run dispatch model in each year to produce hourly outputs for each modelled year and each zone/node

Hourly outputs for each modelled year



Dispatch approach
- The model uses the capacity build-out and determines the least-cost dispatch to meet hourly demand (generator bids are priced on an SRMC basis).
- This is applied to each granular location simultaneously within GB (and across Europe).

Expected outputs
- **Generation / consumption** by each resource on the system on an hourly basis
- Associated **wholesale prices** at each node/zone.
- **Flows** between each zone / node / countries (this would cover curtailment of renewables, Interconnector flows, storage operations and transmission losses among others).
- **Congestion and losses rent** are calculated using the outputs determined by the model

- For the national / zonal markets, the short-term (ST without intra-national / intra-zonal constraints. This

Dispatch approach appears to be **deterministic only.** A **stochastic approach** with variations in inputs such as weather, commodity prices and outages should be combined with a large number of scenarios to capture range of outcomes possible.

How is **scarcity value** captured in the modelling? The ability of generators to capture scarcity rents well above SRMC-based pricing should be considered within the assessment (particularly given recent high market prices).

Wind levels should vary across the country to be able to capture the effects of diversity. **Geospatial modelling should be implemented to ensure benefits from geographic diversity are captured**.

The key outputs that are required to assess the benefits are captured. All results from the modelling should be provided to stakeholders to be able to interpret the results.

The approach to flows between zones will capture the congestion volumes which are a key output of the analysis

Capacity buildout decisions appear to rely on perfect foresight.

Assuming perfect foresight in investment decisions **will overestimate the effectiveness of locational signals** and the ability to reduce constraint costs. This could lead to a significant overestimate in the benefits of nodal/zonal pricing.

Perfect foresight between build decisions and assumed outturn should not be assumed. **An approach that recognises the uncertainties (& potential asymmetries in outcomes) should be employed**. Instead, a range of outcomes should be simulated to capture the range in benefits, including potential asymmetry.

Contracts for Difference

The approach to CfDs should be carefully considered given the importance of this policy

Transmission capacity | Electricity demand | Generation capacity build-out | Run dispatch model | Additional quant. analysis

FTI CONSULTING

Step 5: The approach to assessing the impact of CFDs to inform our modelling will vary across market designs depending on whether CFD generators are existing or new.

- Our modelling assumes an **efficient dispatch and siting of CFD-based generation**, responding to locational wholesale electricity prices
- New generators with CFDs will be **allocated to different locations endogenously**, based on expected future wholesale electricity prices subject to other real-world constraints (e.g. no onshore wind in England)
- We recognise that the **existing CFD regime** would need to be **adapted to be compatible** with locational pricing

Q: What are your views on our approach to modelling CFD contract holders?

Key principles for CFD regime design

Existing (legacy) CFD contracts	New CFD arrangements
▪ Honour existing contracts and obligations ▪ Likely to include a continuation of existing strike prices, and risk exposure (e.g. through 'tail risk')	▪ Continued competitive allocation of contracts based on CFD strike price auction ▪ Efficient allocation of risks between generators and consumers ▪ Efficient siting incentives for new generation, reflecting transmission network / locational prices (currently absent from the existing CFD regime)

The approach to CfDs is unclear and given the importance of this policy, must be considered carefully. FTRs are an imperfect hedge for intermittent generators due to volume risk and limited time horizon. Additionally, if there is no party willing to trade the FTR with the generator then the generator will incur a cost for reducing their risk.

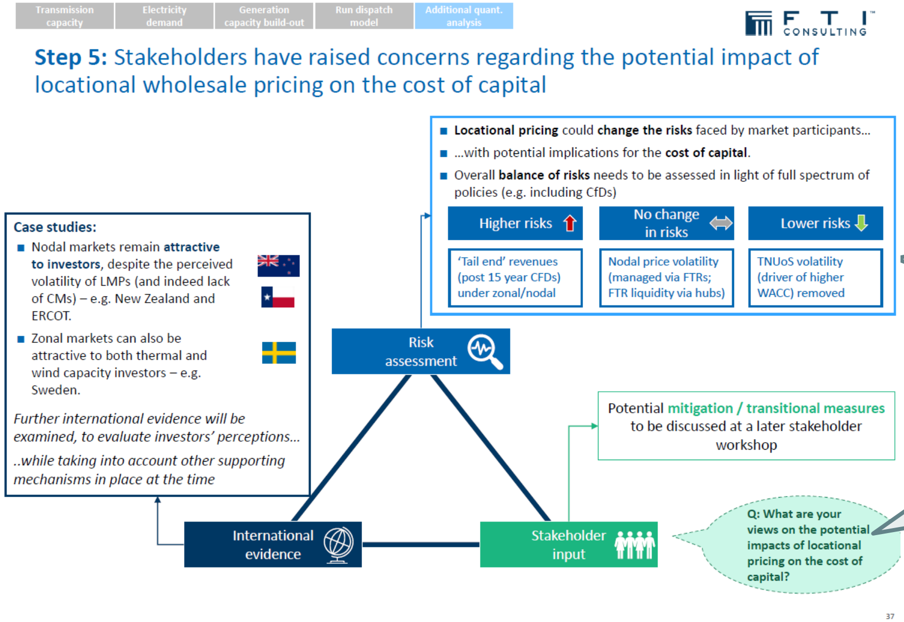
For efficient siting of new generation, this would also require changes to the CfD regime as nodal pricing would not be a sufficient driver of where a plant is located if the plant has a fixed strike price under the CfD. This is because the price a CfD plant receives will not vary by node/zone. **The changes to the CfD regime that are required,** as well as their potential impact on capacity build and cost of capital, **should be explored within the assessment**

The impact of a CfD plant on other plants within the same zone/node should be considered. With the CfD plant being incentivised to generate all the time, this could effect the dispatch of other plants in the same zone and affect their profitability. This could be a particular issue if the unsupported plant decided to locate in that zone to capture benefits of locational wholesale pricing before the CfD plant was built.

It is unclear how the negative pricing rule is included and how this would interact with nodal pricing. Including the negative pricing rule (implemented for AR4+) would likely mean more zero, rather than negative, wholesale prices across nodes/zones.

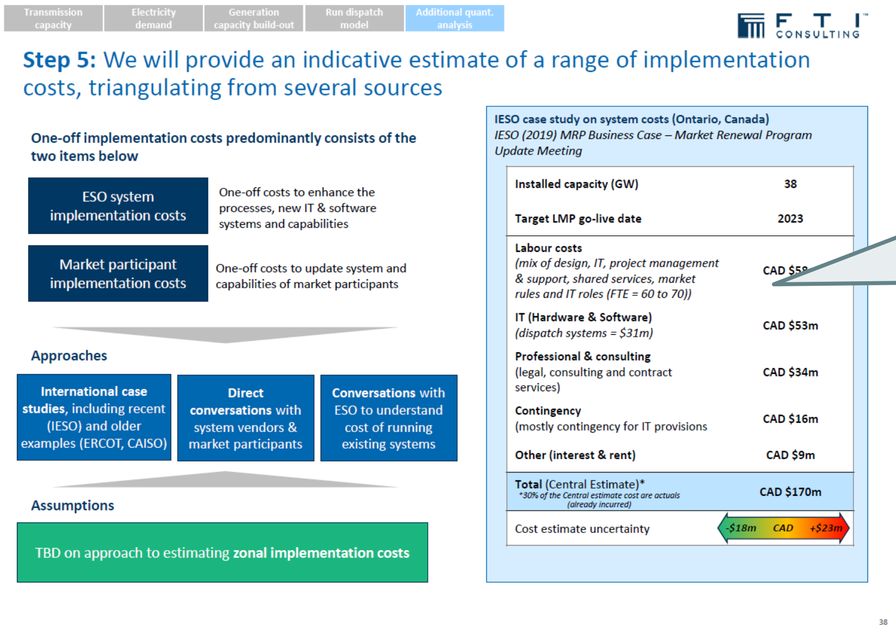
Cost impacts

Including cost impacts of implementing locational granularity is vital for a full assessment



It is likely that implementing locational wholesale pricing will increase cost of capital due to the increased uncertainty from a transition period. **Cost of capital impacts should be included within the modelling but it is not clear if they will be at present**

In addition to including implementation costs within the assessment, **other impacts of implementation need to be considered such as delayed investment due to a transition period**. A change of this magnitude to the system would take years to implement likely resulting in delayed investment and build of new capacity. This should be factored into the assessment.



When locational wholesale pricing is implemented is not stated. Given the magnitude of this change, **it is unlikely any changes will come in before 2027**. This is important given that constraint costs in the scenarios tested peak earlier than this.

Therefore, an **overnight implementation should not be assumed** (as was assumed in FTI's work for Octopus/ESC) as this would likely overstate the benefits.

Summary of modelling process

Limitations in the current modelling process mean modifications to approach and assumptions are required to give balanced assessment

LCP INSIGHT CLARITY ADVICE

frontier economics

Locational granularity

National market | Zonal market | Nodal market

Proposed modelling scenarios

- FES 2021 scenarios are limited in range of outcomes, e.g. very similar demand.
- FES 2021 scenarios are out of date (not consistent with BESS).

Key inputs

1 Transmission capacity

- Scenarios should test alternative (e.g. faster) deployment of network investment & vary this between scenarios

2 Demand

- More transparency needed on demand assumptions, particularly demand locations.

3 Generation capacity

- Assumptions should capture differences in technology costs & load factors of different locations.
- Scenarios should test the impact of alternative capacity mixes.
- Other constraints on build should be included.

Power Market Model

PLEXOS

Long Term Capacity Expansion model

- Capacity in national pricing counterfactual should be optimally located against current (or improved version of current) investment signals, not just taken from FES.
- Modelling should avoid using a single deterministic view of outcomes in evaluating investment decisions.
- Modelling should not assume perfect foresight between build decisions and assumed outturn. A range of outcomes should be simulated to capture range in benefits, including potential asymmetries in outcomes.

Short Term Dispatch Model

- Stochastic modelling, with variations in inputs such as weather, commodity prices and outages, should be implemented to capture range of outcomes.
- Geospatial modelling should be implemented to ensure benefits of geographic diversity, particularly for wind, is captured.
- Impacts on levels of scarcity pricing from be assessed.

Hourly outputs for each modelled year

- Transparency on how plant location decisions are made within the model and how conclusions are made from the model results is needed.
- The results from the various scenarios need to reflect the significant uncertainties within the GB market.

Cost Benefit Analysis

- CBA should be conducted on a system cost basis (not consumer cost basis).
- A breakdown of benefits, particularly the impacts of demand portability, should be provided for stakeholders to interpret results.
- Other potential costs and how this affects meeting emissions targets and energy security, such as delayed investment over transition period, should be included.

Key Recommendations

Changes should be made to modelling approach and assumptions to provide a robust assessment of locational wholesale pricing

1. The assessment is too limited in scope. To fully assess the benefits of introducing locational wholesale pricing, alternative changes to market arrangements should also be tested.
2. The assessment should be conducted on a system cost, not just consumer cost, basis supported by analysis of distributional impacts in line with government appraisal guidance.
3. Given the significant uncertainties involved in the GB energy market over the coming decades, the assessment needs to have a much greater regard to how uncertainty will affect the modelling and results.
4. More transparency and detail is required on many elements of the modelling approach and assumptions, such as approach to setting plant locations, demand assumptions, implementation date and CfD impacts.
5. The national pricing counterfactual should include changes to the TNUoS regime and plant locations should be optimised for that regime in order to avoid overstating the benefits of nodal pricing.
6. Where plants are located should reflect real life decisions made by plants as closely as possible. They should not have perfect foresight of prices but should include other factors that influence decisions on location.
7. Some of the potential impacts of transitioning to a locational pricing system, such as impacts on cost of capital and delayed investment due to a transition period, are not included or the approach is unclear.
8. FES 2021 scenarios are out of date and are limited in their range of outcomes. Further scenarios should be tested as part of the main assessment to capture a wider range of possible future outcomes.
9. Scenarios should test faster transmission build than assumed under NOA. A range of capacity differences between nodal & non-nodal models should be used to test whether reduced transmission investment may be a benefit.